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PUC DOCKET NO. 51415 53

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

<u>EASTMAN CHEMICAL COMPANY'S RESPONSE TO SOUTHWESTERN ELECTRIC POWER COMPANY'S FIRST REQUESTS FOR INFORMATION</u>

Eastman Chemical Company ("Eastman") files this Response to Southwestern Electric Power Company's First Requests for Information to Eastman Chemical Company. Eastman's responses to requests for information that were filed before Eastman's direct testimony was filed were to be made within twenty (20) calendar days, making the responses due by April 19, 2021. By agreement with SWEPCO counsel, Eastman agreed to respond to these requests for information on or before April 15, 2021. This response is therefore timely. All parties may treat the answers as if they were filed under oath.

Eastman files these responses without agreeing to the relevancy of the information sought and without waiving its right to object at the time of the hearing to the admissibility of information produced herein.

Respectfully submitted,

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By: ______________________
ATTORNEYS FOR EASTMAN CHEMICAL COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of this document was served by electronic mail, on all parties of record in this proceeding on April 15, 2021, in accordance with the Orders Suspending Rules, issued in Project No. 50664.

____
Katherine K. Mudge

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

EASTMAN CHEMICAL COMPANY'S RESPONSE TO SOUTHWESTERN ELECTRIC POWER COMPANY'S FIRST REQUESTS FOR INFORMATION

Question No. SWEPCO 1-1:

Please provide all communications from Eastman or on behalf of Eastman, to the Southwest Power Pool (SPP), or any of its representatives, that addresses SPP's treatment of electricity produced and consumed on-site behind a retail customer's meter in assessing transmission charges under the SPP Open Access Transmission Tariff.

Response No. SWEPCO 1-1:

See TIEC Response to SWEPCO-TIEC 1 for all responsive communications from or on behalf of Eastman.

Prepared by or under the direction of the following Sponsor: Anthony Murray

Witness: N/A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

EASTMAN CHEMICAL COMPANY'S RESPONSE TO SOUTHWESTERN ELECTRIC POWER COMPANY'S FIRST REQUESTS FOR INFORMATION

Question No. SWEPCO 1-2:

Please provide all documents addressing or analyzing SPP's treatment of electricity produced and consumed on-site behind a retail customer's meter in assessing transmission charges under the SPP Open Access Transmission Tariff.

Response No. SWEPCO 1-2:

Subject to the following limitations agreed to by SWEPCO to this RFI: (1) time frame back to December 2018, (2) does not include attorney client or attorney work product communications and/or documents, and (3) does not include correspondence between Eastman and SWEPCO and/or AEP on this issue, see responsive documents marked:

- Eastman Response 1-2 Attachment 1 (Confidential)
- Eastman Response 1-2 Attachment 2
- Eastman Response 1-2 Attachment 3 (Confidential)
- Eastman Response 1-2 Attachment 4 (Confidential)

Portions of each Attachment are redacted to remove non-responsive content or attorney/client and/or attorney work product privileged content. Contemporaneously with filing this response, Eastman is also providing a privilege log to SWEPCO that identifies documents that are covered by the attorney/client and/or attorney work product privilege and are not being produced.

Prepared by or under the direction of the following Sponsor: Anthony Murray

Witness: N/A

From: VanMiddlesworth, Rex <RexVanM@tklaw.com>
Sent: Tuesday, February 12, 2019 5:06 PM
To: Joan Walker-Ratliff; Murray, Anthony F; Glen Lyons; Bill Smith (bill.smith@airliquide.com); Melissa Trevino; brenda_harris@oxy.com; Suzanne_B_Mottin@oxy.com
Subject: [I] FW: Behind-the-meter-generation issue in SPP
Attachments: BTMG-btmg Comments 10-18-17 (C0105693).pdf; 20180117 PAC Item 03d ABATE_IIEC_LEUG_TIEC_CMTC_APGI Presentation105491.pdf; 20190213 PAC Item 03a BTMG-btmg (PAC003)318041.pdf

[redacted]

Rex VanMiddlesworth | Thompson & Knight LLP
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From: VanMiddlesworth, Rex
Sent: Tuesday, February 12, 2019 5:02 PM
To: William Coe (wcoe@dwmrlaw.com) <wcoe@dwmrlaw.com>
Subject: Behind-the-meter-generation issue in SPP

Bill, this is to follow up on AEP's request to provide briefing on our view of the behind-the-meter issue, particularly as it relates to qualifying cogeneration facilities. First, I have attached a letter brief filed on behalf of a number of industrial groups in the MISO area when this issue came up there in 2017. I have also attached a 2018 PP presentation to MISO on this issue by Jim Dauphinais of BAI. My understanding is that MISO, which has similar tariff provisions to those of SPP, has not chosen to allocate costs to load served by behind-the-meter generation (btmg), as discussed in the attached materials. Instead, MISO initiated a stakeholder process to: (i) further explore the treatment of MISO Network Integration Transmission Service charges for load served by behind the meter generation and (ii) propose tariff language changes to clarify that treatment. The brief and 2018 PP touch on the QF issue, as well as the FERC precedent on this issue. I would also note that MISO in a recent presentation indicated that it is proper to apply Network Integration Transmission Service charges to load served by retail behind the meter on a net basis, to permit limited incidental use of the transmission system for that netting (e.g., for adjacent customer facilities), and to allow netting for wholesale behind the meter generation when the load served by that generation is either lost or cannot be served when the generation is not operating. A copy of the recent MISO presentation is also attached.

In addition, I'd add the following comments.

Treatment of QFs

The allocation of costs to load served by QFs was an important issue in the development of the PURPA regulations concerning rates for Qualifying Facilities. The concern was that utilities would assign costs for back-up power as if the load served by the QF was always taking service simultaneous with the system peak, and the PURPA regulations specifically prohibited that assumption, unless it was actually supported by factual data. 18 CFR 292.305. Yet, the new SPP policy, if applied to QFs, would impose that very assumption, despite the fact that is not supported by factual data. That is, transmission costs would be assigned to load served by QFs as if the load required back-up power for each of the 12 monthly peaks.

The FERC comments issued concurrently with the PURPA regulations make this point even more clearly, stating that a QF may receive standby power "at a nondiscriminatory rate which reflects the *probability* that the qualifying facility will or will not contribute to the need for and use of utility capacity." 45 Fed. Reg. No. 38, p 12228 (Feb 25, 1980) (emphasis supplied). The use of actual 12 CP loads imposed on the SPP transmission system over time reflects such a probabilistic analysis, but SPP would instead assume a 100% probability that the cogeneration was experiencing an outage at the time of the system peak. Indeed, SPP's assumption is even more extreme, as in many cases the actual load at a Qualifying Facility drops when the electricity and steam generation go down, such QFs would never impose on the utility's transmission system the full amount of the QF-served load. Yet, this is what the new SPP methodology would assume.

You may be familiar with the fact that FERC has determined that the PURPA-Put regulations no longer apply if there is a functioning wholesale market. That decision, however, does not apply to the other PURPA regulations, such as those discussed above.

Application of Existing SPP OATT

As noted on pp. 30-32 of SPP's March 28, 2018, PowerPoint presentation, multiple SPP Network Customers do not include retail load served by behind-the-retail-meter-generation in their determination of Monthly Network Load. That approach is not only commonplace, but it is consistent with the SPP OATT's definition of "Monthly Network Load" in Section 34.4. Specifically, the Monthly Network Load for a Network Customer is the Network Customer's "hourly load consistent with the monthly peak of the Zone where the Network Customer is physically located." Load that is not taking service from SWEPCO at the time of the monthly peak is simply not a part of SWEPCO's monthly load at the time of the peak, whether it is an industrial or commercial customer that has reduced its load from its NCP level, a residential customer with rooftop solar or that is not running all its appliances at the time of peak, or an industrial facility that is being served by cogeneration at the time of peak. The OATT defines Monthly Network Load as load actually being served by SWEPCO at the time of the monthly peak. That view is consistent with the view of at least 10 of the respondent's to SPP's survey. If SPP desires to begin assessing transmission costs to load that is not actually a Network Customers hourly load at the time of a monthly peak, it should seek a revision to Section 34.4 of its OATT.

I understand that the issue of behind the meter load has arisen in SPP largely in the context of municipal utilities that have their own generation to serve retail load. That is a very different situation than a retail customer that serves its own load behind a retail meter. A municipal utility is a "Network Customer," and therefore all load served by it at the time of a monthly peak would fall within the definition of Monthly Network Load in Section 34.4 of the SPP OATT. That is, the Network Customer (the Muny) is actually serving that load at the time of the monthly peak (albeit partially with the Muny's own generation). With respect to a *retail* customer's load served behind a retail meter, the Network Customer is simply not serving that load at the time of the monthly peak. Accordingly, it does not come within the terms of Monthly Network Load in Section 34.4.

If it would be helpful to get your folks to talk with our expert on this issue (Jim Dauphinais at BAI), I'd be happy to set up a call. I'll also give you a report on the outcome of the MISO meeting tomorrow, but the expectation is that they will continue to apply their OATT, which I'm told is similar to SPP's, so as not to apply to retail behind the meter generation.
Best, Rex

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Memorandum

TO:	JACOB KRAUSE
FROM:	ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY COALITION OF MISO TRANSMISSION CUSTOMERS ILLINOIS INDUSTRIAL ENERGY CONSUMERS LOUISIANA ENERGY USERS GROUP MIDWEST INDUSTRIAL CUSTOMERS TEXAS INDUSTRIAL ENERGY CONSUMERS
DATE:	OCTOBER 18, 2017
RE:	COMMENTS ON MISO'S PROPOSED TREATMENT OF BTMG/btmg

This memorandum has been prepared to provide feedback to MISO Staff on their proposed treatment of behind the meter generation. For the purposes of this memorandum, we have defined Behind the Meter Generation (uppercase BTMG in MISO's approved Open Access Transmission Tariff or "OATT") as behind the meter generation that has elected to register as a Load Modifying Resource because it has voluntarily chosen to participate as a MISO market participant in the MISO capacity market and it is not otherwise registered with MISO as a Generation Resource or Demand Response Resource. We have defined behind the meter generation (lowercase btmg) as a generation resource behind the meter of a retail customer within the MISO footprint that is not a MISO market participant and has elected not to register as an LMR.

At the September 27, 2017 meeting of MISO's Planning Advisory Committee ("PAC"), MISO Staff presented its interpretation of the required treatment of both BMTG and btmg for the purpose of billing network integration transmission service ("NITS") under MISO's OATT. As we understand MISO Staff's position, they have stated that both BMTG and btmg must be grossed up for the purpose of establishing monthly billing demand for NITS under MISO's OATT. While we do not disagree that this is correct for wholesale BMTG based upon MISO's OATT and FERC precedent, we fundamentally disagree that this interpretation is correct, consistent with FERC precedent, or practical in the real world, with respect to btmg. This memorandum outlines the facts in support of this conclusion.

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FERC PRECEDENT

In its September 29, 2017 presentation, MISO Staff cited three cases to support its conclusion that the billing for NITS service required both BMTG and btmg to be grossed up for the purposes of establishing NITS monthly billing demand. In reality, there is a much longer history of relevant FERC cases.

FERC has consistently held that the allocation of demand costs, including transmission costs, should be based on a customer's actual usage coincident to peak system demand (*see PJM Market Rules, Occidental, Bear Island, Entergy*).[1] FERC has also weighed in specifically on the assignment of costs for NITS service for customers with btmg, finding that for these customers, the correct NITS billing determinant is the customer's net load (*PJM Market Rules, Entergy*). The decisions in these cases stretch from 2003 to 2015.

FERC has upheld requirements that transmission customers with BTMG report gross loads to a regional transmission organization on the basis that the information was necessary for operational and planning purposes and required to be provided by tariff (*PJM Market Rules, Prairieland*). FERC has also held that a customer load at a discrete delivery point may elect to take either NITS or Point-to-Point Transmission Service, but that a load at a discrete delivery point could not elect to receive NITS for only a portion of its total load (*Order 888, Prairieland*). The overlap of these cases (1996-2010) to the cases specifically addressing issues of cost allocations further demonstrates that the issues presented in these other contexts should not be interpreted as conclusive for purposes of assigning NITS costs.

Relevant FERC cases that address this issue of BMTM/btmg are identified and summarized below:

MISO Formation Case

Order 453-A (Feb. 13, 2002)

On January 15, 1998, ten transmission-owning public utilities sought approval of the MISO Tariff and MISO Agreement, and to transfer operational control of their transmission facilities to MISO.[2] As part of the voluntary agreement reached by the parties, transmission owners, during a six-year transition period, could only take network service to serve bundled load if they met two conditions.[3] Because bundled load would not be receiving network service during the transition period, the applicants

[1] These cases are discussed later in this memorandum.

[2] *Midwest Independent Transmission System Operator, Inc.*, ER98-1438-008, Opinion No. 453-A, Order Denying in Part and Granting in Part Rehearing and Providing Clarification at 2 (Feb. 13, 2002).

[3] *Id.* at 6.

proposed to exclude that load from MISO's Cost Adder.[4] The Cost Adder reimbursed MISO for services it performs that benefit all users of the grid (*e.g.*, unified scheduling and ATC calculation, and regional planning).[5] Because bundled network load was not served through NITS, the treatment of btmg for NITS billing purposes was never addressed.

On rehearing, the applicants requested FERC to confirm that they were not required to pay MISO's Cost Adder for bundled load, but if they were to allow them to take network service on behalf of bundled load.[6] FERC clarified that its initial order required that the load of bundled load be included in the divisor of the Cost Adder.[7] FERC held that all users of the grid will receive benefits when it is operated and planned by a single regional entity.[8] "[L]oad served from generation located on an individual transmission owner's system ... can not [sic] be served reliably without the facilities operated by Midwest ISO."[9] Further, placing all load under MISO's Tariff, and thus subject to the Cost Adder, was consistent with the RTO requirement that it be the only provider of transmission service over facilities under its control.[10] FERC thus concluded that all customers, including bundled load, should pay the Cost Adder because they all benefitted from the grid.[11] FERC further clarified that this requirement did not mean that the Cost Adder could directly be assigned to bundled load.

In light of its clarification on rehearing, FERC granted further rehearing to allow all stakeholder views on the issue to be addressed in Docket ER98-1438-010.[12] MISO made its proposed revision in that docket to allow bundled load to take network service, which went unopposed and was ultimately approved by FERC. As to the recovery of the Cost Adder by the transmission owners from bundled loads, FERC held that this was an issue to be raised with individual state commissions.[13]

This case did not address issues of cost assignment to individual retail customers as bundled retail customers were not taking network integration transmission service under MISO's original open access transmission tariff.

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[4] *Id.* at 6, 8-9.

[5] *Midwest Independent Transmission System Operator, Inc.*, ER98-1438-010, Order Conditionally Accepting Tariff Provisions for Filing, Ordering Further Compliance Filing, and Denying Motion to Consolidate at 6 (Oct. 31, 2002).

[6] *Midwest Independent Transmission System Operator, Inc.*, ER98-1438-008, Opinion No. 453-A, Order Denying in Part and Granting in Part Rehearing and Providing Clarification at 8-9 (Feb. 13, 2002).

[7] *Id.* at 11.

[8] *Id.* at 8.

[9] *Id.* at 9.

[10] *Id.* at 11.

[11] *Id.* at 9.

[12] *Id.* at 13.

[13] *Id.*

ITC Transmission Rate Settlement (2003)

Settlement

The settlement addressed rates in the International Transmission Company ("ITC") Zone from the period of June 1, 2002 through February 28, 2003.[14] In the course of the proceeding, several parties raised issues regarding the treatment of load served by behind the meter generation.[15] The settlement required MISO to make an informational filing with FERC addressing load served by behind the meter generation.

MISO's Settlement Filing Regarding Load Served by Behind the Meter Generation (July 22, 2003)

In its informational filing required by the aforementioned settlement, MISO claimed that its OATT was sufficiently clear and provided that charges for NITS included load served by behind the meter generation.[16] In support of its position, MISO referred to multiple sections of its OATT as well as prior FERC decisions. With respect to its OATT, MISO claimed that the denominator in its calculation of NITS rates included the load reported by individual transmission owners.[17] In particular, MISO claimed that the treatment of Network Customer transmission rights supported its view.[18] In this regard, MISO noted that Section 30.8 of its OATT permitted Network Customers to use control area interface capacity.[19] With respect to this provision, MISO claimed generation Network Load behind the meter had a right to Transmission System capacity.[20] MISO, therefore, concluded that "Network Customers with load served by generation behind the meter can claim a right to Transmission System capacity that is on the control area side of the meter."[21]

MISO also noted that the OATT consistently ignored the location of the generator when it quantifies load.[22] Further, MISO claimed that in an older version of its External

[14] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000, Offer of Settlement at 1-2 (July 9, 2003).

[15] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000 Explanation in Support of Offer of Settlement at 2 (July 9, 2003).

[16] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000, MISO Letter at 6 (July 22, 2003). In its informational filing MISO referenced lowercase behind the meter generation.

[17] *Id.* at 3.

[18] *Id.* at 5.

[19] *Id.* at 6.

[20] *Id.*

[21] *Id.*

[22] *Id.*

Interface Specification, a memorandum circulated to stakeholder groups, it "expected load behind the meter to be reported for the External Interface Specification."[23]

MISO also argued that its interpretation was consistent with FERC guidance. In Order 888-A, MISO quoted FERC as holding "[a] request for network service is a request for the *integration* of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated – it is either fully integrated or not integrated."[24]

Based on the forgoing, MISO concluded that the definition of Network Load included load served by behind the meter generation.

Municipal Parties' Response to MISO Informational Filing (Aug. 15, 2003)

In response to MISO's letter, several municipalities and municipal utilities submitted a joint filing arguing that MISO's letter only served to "highlight[] the problems with MISO's view associated with the current policy, including conflicting understandings of the current policy and the lack of uniformity in the application, reporting and enforcement thereof."[25] The Municipal Parties alleged that the inclusion of load served by behind the meter generation renders Network Service an economically infeasible transmission option for many parties that would otherwise convert to Network Service.[26] Specifically, they asserted that MISO's policy would require a customer to purchase Network Service for its entire load, regardless of the amount of transmission service that the customer actually needs or uses.[27] They concluded that MISO's policy did not bear a rational relationship between a customer's proportionate use of the transmission system and the amount it was charged for the use of the system.[28]

They further alleged that MISO's current policy was not uniformly understood, followed, or enforced.[29] Finally, they alleged that MISO's policy unduly discriminated against parties that had historically invested in local generation.[30] Accordingly, they asked FERC to initiate a review under Section 206 as to whether it was appropriate to include load served by behind the meter generation in the billing determinants for network service.[31]

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[23] *Id.* at 7.

[24] *Id.* (*quoting* Order 888-A, 62 Fed. Reg. 12,274, at 12,323).

[25] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000, Municipal Parties' Response to MISO at 1 (Aug. 15, 2003).

[26] *Id.* at 2-3.

[27] *Id.* at 2.

[28] *Id.*

[29] *Id.* at 4-5.

[30] *Id.* at 5-6.

[31] *Id.* at 6.

METC Response to Municipal Parties' Response (Sept. 3, 2003)

Michigan Electric Transmission Company ("METC") also weighed in, opposing the Municipal Parties' request for a Section 206 investigation. According to METC, the appropriate treatment of behind the meter generation for Network Load had already been resolved by the prior FERC decisions that MISO cited in its filing.[32] METC also opposed resolving the broad policy issue in the context of the proceeding, which was initiated to address ITC's transmission rates.[33]

Order Approving Uncontested Settlement (Oct. 17, 2003)

On October 17, 2003, FERC issued its order approving the terms of the settlement with respect to the ITC rate issues.[34] The FERC order did not address the BTMG/btmg generation issue, or the filings on that subject by MISO, the Municipal Parties, or METC.

Prairieland Complaint (2010)

In this proceeding, FERC granted Ameren Services Company's ("Ameren") complaint against Prairieland Energy, Inc. ("Prairieland") regarding underbilled NITS service due to unknown BTMG.[35] Prairieland is a wholly-owned subsidiary of the University of Illinois, who buys power for resale to the University.[36] Thus, by virtue of its business decisions, Prairieland became a wholesale customer taking service under MISO's OATT and registered its behind the meter generation with MISO as BTMG. Beginning October 27, 2006, Prairieland and MISO entered into an agreement under which the University, through Prairieland, received Network Service over transmission facilities operated by MISO.[37] A second agreement was entered into with Ameren, under which Ameren agreed to submit electronic billing data to MISO to allow MISO to bill Prairieland.[38] In 2008, Ameren became aware that the University had MISO-registered BTMG and had been billed on a net load basis instead of a gross load basis. Prairieland ultimately provided Ameren with its generation data.[39] Beginning April 2009,

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[32] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000, Response of Michigan Electric Transmission Company, LLC to the Response of the City of Wyandotte, Michigan, *et al.*, to Midwest Independent Transmission System Operator, Inc.'s Informational Filing at 2-5 (Sept. 2, 2003).

[33] *Id.* at 5-6.

[34] *Midwest Independent Transmission System Operator, Inc.*, ER02-1963-000, Order Approving Uncontested Settlement (Oct. 17, 2003).

[35] *Ameren Services Co. v. Prairieland Energy, Inc.*, EL09-069-000, Order Granting Complaint at 1-2 (May 7, 2010).

[36] *Id.* at P1, footnote 1.

[37] *Id.* at P5.

[38] *Id.* at P6.

[39] *Id.*

Prairieland was billed on a gross load basis.[40] The complaint addressed an invoice Ameren sent to Prairieland seeking to rebill Prairieland on a gross load basis for the period of January 2007 through February 2009.[41]

Prairieland argued that the under billing for historic consumption was a billing error by Ameren that was beyond the 90-day timeframe for resettlement.[42] FERC disagreed.

FERC determined that as a Transmission Customer under the Network Service provisions of the Tariff, Prairieland was required to supply MISO with the information MISO deemed reasonably necessary to provide the requested service.[43] This included a description of the Network Load at each delivery point.[44] The definition of Network Load provides that a customer "may not designate only part of the load at a discrete Point of Delivery."[45] FERC determined that Prairieland failed to comply with this requirement by not designating its total load as Network Load.[46] Based on this determination, FERC found that Prairieland had violated its service agreement and MISO's tariff, and therefore granted Ameren's complaint.

Entergy Integration into MISO (2015)

As part of its proposed integration into MISO, Entergy proposed certain changes to its System Agreement among various affiliated operating companies.[47] Included in its proposal was the calculation of Company Load Responsibility.[48] Specifically, Entergy proposed to incorporate retail btmg into the calculation of hourly load.[49] Entergy explained that retail btmg would reduce MISO load values for an Entergy Operating Company, but because an Entergy Operating Company would still have an obligation to serve that load, it should be added back for purposes of allocating costs under the System Agreement.[50] Entergy argued that this would maintain the status quo of what would have occurred under the System Agreement prior to integration into MISO.

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40 *Id.*

41 *Id.*

42 *Id.* at P21-22.

43 *Id.* at P26.

44 *Id.*

45 *Id.* at P27.

46 *Id.* at P28.

47 *Entergy Services, Inc.*, ER14-73-000, 152 FERC ¶ 61,133, Order Conditionally Accepting Amendments to the Entergy System Agreement at 1 (Aug. 18, 2015).

48 *Id.* at P11.

49 *Id.* At P12.

50 *Id.* at P43.

Among other challenges, protests were filed by industrial customers and customer groups regarding Entergy's changes specific to the treatment of btmg.[51]

FERC modified and approved Entergy's proposal. Finding that "Company Load Responsibility and Responsibility Ratios are used to allocate costs and benefits on the Entergy System based upon the relative share of individual Entergy Operating Company load to total System load," FERC determined that it was appropriate to include in the allocation among the Entergy operating companies _some_ load served by behind the meter generation.[52] FERC found that it was reasonable to include _net_ injections in the allocation of costs and benefits among the Entergy Operating Companies, but that it was unreasonable to include btmg that "serves only the load of the resource owner and not system load."[53]

Thus, for load served by retail btmg, FERC required Entergy to use a customer's net load in the allocation of costs and benefits under the Entergy System Agreement.

Occidental Complaint (2003)

While the summaries above relate to MISO cases, several FERC decisions involving PJM are also relevant to the issue of the treatment of BTMG/btmg generation for purposes of calculating transmission cost responsibility. In this case, FERC found that PJM's allocation of its network access charge costs was unjust and unreasonable, to the extent the methodology adds back certain curtailed load in determining a customer's coincident peak usage.[54]

The issues in this proceeding were brought before FERC pursuant to a complaint filed by an industrial customer, Occidental Chemical Corporation ("Occidental").[55] In its order on the complaint, FERC found that part of PJM's transmission formula for allocating PJM's network access charges was correct.[56] Specifically, FERC found that the component of the formula which was based on a customer's actual load (both firm and non-firm) coincident with the annual peak of the zone was reasonable.[57] However, FERC rejected the portion of PJM's formula that added back curtailed load to its allocation of network costs.[58] FERC found that this was inconsistent with its "underlying

[51] *Id.* at P23-34.

[52] *Id.* at P44.

[53] *Id.* at P45.

[54] *Occidental Chemical Corp. v. PJM Interconnection, L.L.C. and Delmarva Power & Light Co.*, EL02-121-001, 102 FERC ¶ 61,275, Order on Compliance Filing and Rehearing at 1 (Mar. 12, 2003).

[55] *Id.* at P3.

[56] *Id.* at P4.

[57] *Id.*

[58] *Id.*

rationale of reducing a customer's costs when it reduces load during system peaks."[59] FERC therefore directed PJM to remove from its formula an allocation of costs to curtailed load or, alternatively, to provide an explanation of why such an allocation was reasonable.[60]

PJM opted for the alternative approach, and submitted a compliance filing defending the use of curtailed load as an allocation factor.[61] FERC again rejected PJM's approach. In again rejecting PJM's proposed allocation methodology, FERC reaffirmed its finding that "[a]ccess charges for use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost causation."[62] FERC continued its explanation, stating that "[w]hile PJM's consideration of curtailed loads may be one of many factors that is appropriate to consider for transmission planning purposes, its inclusion as an allocation factor ... is not justified."[63] FERC further found that "PJM's add-back provision is not consistent with the need to encourage load response during periods when generation or transmission are in short supply and prices are rising."[64] Finally, FERC rejected PJM's cost-shift argument because "[t]he other customers are making greater use of the system during the system coincident peak and are therefore justifiably assigned a larger percentage of costs."[65]

Thus, this case demonstrates that NITS costs should be billed to customers with on-site btmg based on their "actual," or net load coincident with the transmission system peak.

PJM Market Rules (2004)

In this case, FERC accepted PJM's proposed modifications to its OATT and related agreements to implement market rules for behind the meter generation, subject to certain conditions.[66] In its proposal, PJM noted under its market rules then in effect, market participants were charged for network service, energy, capacity, ancillary services, and PJM administrative fees based on their total load or scheduled load, as applicable.[67] However, PJM noted that over the prior year its stakeholders had been

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[59] *Id.*

[60] *Id.*

[61] *Id.* at P6-7.

[62] *Id.* at P14.

[63] *Id.*

[64] *Id.* at P16.

[65] *Id.*

[66] *In re PJM Interconnection*, ER04-608-000, ¶ 61,113, Order Accepting Market Rules, Subject to Condition at 1 (May 6, 2004).

[67] *Id.* at P3.

working to develop rules for behind the meter generation.[68] The stakeholder process culminated in three proposals that were presented to PJM's Electricity Market Committee ranging from total netting of btmg to using gross load.[69] After considering the proposal, PJM adopted the total netting approach, which was set forth in its filing before FERC.[70]

PJM explained that its rule change would encourage increased use of btmg to serve loads because customers would be able to reduce their costs by netting behind the meter generation in the calculation of PJM's charges.[71] PJM asserted that its approach would encourage use of btmg during times of scarcity and high prices, "thus increasing the opportunity for load to compete in PJM markets."[72] PJM also argued that this approach was consistent with FERC's policy that those that rely to a lesser degree on PJM's integrated transmission system should be allocated a lesser proportion of the costs.[73] Finally, PJM explained that its proposal was limited to btmg that directly serves load at the same site or single electrical location (PJM also explained that it anticipated further discussion through the stakeholder process on the expansion of netting in other circumstances, such as municipal or cooperative systems).[74]

All parties to the proceeding supported PJM's netting approach, with the disagreement largely focusing on whether PJM's netting proposal should be expanded in this proceeding to, for example, municipal systems with BTMG.[75] PJM responded that its proposal did not cover municipal systems because they are often connected to the transmission system at multiple points, requiring BTMG to use the PJM transmission system to serve load.[76] PJM reiterated that the purpose of its proposal was to "ensure that only generation that does not rely on the transmission system is netted against load for purpose of determining the charges for PJM's various services."[77]

FERC approved PJM's proposal, finding that "consistent with [its] policy of encouraging demand response programs, PJM's proposed market rules are just and reasonable and will encourage qualifying entities with behind the meter generation to reduce their use of the PJM transmission system."[78] FERC found that this approach

[68] *Id.* at P2.

[69] *Id.* at P4.

[70] *Id.*

[71] *Id.* at P6.

[72] *Id.*

[73] *Id.*

[74] *Id.* at P6-7.

[75] *Id.* at P15.

[76] *Id.* at P21.

[77] *Id.*

[78] *Id.* at P27.

was consistent with its holding in *Occidental*, that "charges for the use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost causation."[79]

With respect to municipal systems, FERC found that the protestors had failed to provide sufficient evidence to demonstrate that they were similarly situated to directly connected load.[80] "[U]nlike industrial generators," FERC explained, "the municipal generators have failed to show that their generation does not make use of the transmission system, such that they should be relieved of paying the applicable charges."[81]

FERC precedent is that customers with on-site btmg meter generation should be billed for NITS based on net load.

MISO'S TARIFF

As these cases discussed above make clear, FERC has consistently found that customers should be charged costs based on customers' actual demand coincident with peak demand. For customers with on-site behind the meter generation, FERC has found that the correct billing for NITS should be based on the customer's net load coincident with the transmission system peak. These FERC decisions temporally overlap with other FERC decisions addressing issues impacted by behind the meter generation, but not specifically cost assignment. Because these cases overlap in time with the more specific cost assignment decisions, FERC's decisions specific to cost assignment should be used as a guide by MISO in calculating the correct billing determinant for NITS for customers with on-site behind the meter generation. More specifically, MISO should bill customers with on-site behind the meter generation for NITS based on the customer's net load.

MISO's OATT

Although MISO Staff has stated its OATT requires both BTMG and btmg to be invoiced for NITS based upon gross load, MISO's OATT is less than clear on this issue.[82] Specifically Section 34.2 of Module B of MISO's tariff, which defines how hourly load is to be reported for the purpose of billing NITS, states as follows:

> A Network Customer's monthly Network Load is its hourly Load (60 minute, Hour); provided, however, the Network Customer's monthly Network Load will

[79] *Id.* at P28.

[80] *Id.* at P30.

[81] *Id.*

[82] In making these observations, we recognize FERC's interpretation of MISO's OATT regarding wholesale BTMG in the Prairieland compliant.

be its hourly Load coincident with the monthly peak of the pricing zone where the Network Customer's Load is physically located or as otherwise located as defined in Section 31.3 (b) or (c).

Transmission losses refer to the loss of energy during the transmission of electricity from generation resources to Load, which is dissipated as heat through transformers, transmission lines, and other transmission facilities that are under the functional control of the Transmission Provider. When reporting monthly network coincident peak loads to MISO for billing purposes, load reporting entities will adjust Network Load to account for Transmission losses in accordance with MISO Business Practice Manual – 012.

Thus, this section of MISO's OATT is silent on the treatment of BMTG/btmg.

Additionally, for the purpose of billing NITS for retail btmg, we believe that MISO has failed to recognize an important distinction. Retail customers taking bundled electric service from an electric utility are not customers under MISO's OATT. Rather, the MISO OATT customer is the vertically integrated electric utility serving retail customers. As such, the vertically integrated electric utility does not own any retail btmg required to be reported to MISO under MISO's OATT.[83] This similarly applies to retail customers taking unbundled retail electric service through Alternative Electric Supplier (Michigan) or Alternative Retail Electric Supplier (Illinois) where the Alternative Electric Supplier or Alternative Retail Electric Supplier (collectively, "Alternative Electric Suppliers") are acting as the transmission customer under the MISO OATT rather than the unbundled retail electric customer itself.

Even if an electric utility or Alternative Electric Supplier serves retail customers that have retail btmg, they likely do not have access to the metered output of all such facilities unless they have specific state commission authorization (for whatever reason) for such access. Within the industrial community submitting comments, the output of behind the meter generation is considered competitively sensitive and trade secret information. Our member companies would not divulge this information in the ordinary course of business, and if required to divulge (through, for example a court order or regulatory decision requiring the information), would insist that the information be protected and not subject to public disclosure. It is not clear whether MISO has any of these types of information protection measures in place.

On a practical level, it is simply not possible to require MISO electric utilities to inventory and gather data on all[84] retail btmg on their systems. Under MISO Staff's interpretation of its tariff, are MISO transmission owners required to inventory and report on all the retail customers that have a portable generator in their garage for use during a

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[83] The vertically integrated utility could have wholesale BMTG required to be reported under MISO's OATT.

[84] The use of the word all is not by accident. We believe MISO Staff's proposed treatment of btmg based upon its September 27 presentation at the PAC would require all btmg to be inventoried and reported.

power outage? What about customers with a Generac unit in the back of their house or homes with PV rooftop solar? A reasonable conclusion is that MISO Staff's proposed treatment of retail btmg is not required under its OATT and is simply not practical or capable of implementation.

Notwithstanding the above, we would also note that any changes MISO proposes with respect to the treatment of btmg should be made as proposed modifications to its OATT and not changes to its business practice manuals alone.

PURPA CONSIDERATIONS

FERC has specific PURPA rules with respect to the provision of backup and maintenance power to btmg that is certified or self-certified as a Qualifying Facility. In particular, those rules require that the rate for sales of backup and maintenance power to Qualifying Facilities:

> "(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities." (18 CFR Ch. I, § 292.305 (c).)

For costs of backup and maintenance power that are driven by system peak demand (*i.e.*, capacity and transmission), this rule specifically prohibits the allocation of these costs to customers on the basis of gross demand (unless supported by factual data) as this would assume the forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both.

OTHER CONSIDERATIONS

Another consideration with respect to Qualifying Facilities is that many of them lose some or all of the behind the meter load that is being served by the Qualifying Facility when that Qualifying Facility experiences an outage. This means they never draw transmission service in an amount equal to their gross load, but rather only transmission service for the portion of their load that remains when the Qualifying Facility is offline.

Additionally, other factors that should be considered when considering the treatment of retail btmg include:

- Combined heat and power ("CHP") has been found to be a particularly efficient method of meeting certain customers' thermal and electrical needs.

- CHP is different from other forms of btmg, such as distributed renewable energy, in that the generation tends to be very reliable, with low EFOR values and, thereby, little chance of forced outage during transmission system peak times.
- Requiring the use of gross load will significantly affect the economics of CHP development and operation and, thus, will likely result in waste of energy resources.

CONCLUSION

The comments have been prepared and submitted on behalf of the industrial groups identified in the transmittal section of this memorandum. We are requesting the comments be publicly posted and shared with other MISO Stakeholders.

Large Retail Customer Perspective Behind the Meter Generation Transmission Charge Netting

MISO Planning Advisory Committee
January 17, 2018

Jim Dauphinais
Brubaker & Associates, Inc.
on behalf of

Association of Businesses Advocating Tariff Equity
Illinois Industrial Energy Consumers
Louisiana Energy Users Group
Texas Industrial Energy Consumers
Coalition of MISO Transmission Customers
Alcoa Power Generating, Inc.

BAI

REVISED

Large Retail Customers and btmg

- Many of the members of the groups sponsoring this presentation have retail behind the meter generation (btmg)
- This generation is typically Combined, Heat and Power (CHP) generation; other cogeneration; or other high capacity factor generation
- These retail customers have pursued this generation to serve their own load with greater efficiency and at a much lower cost
- In some cases this generation is part of a Qualifying Facility that may either: (i) have a net output of as-available energy to the retail customer's Load Serving Entity (LSE) or (ii) provide net capacity and/or energy into the MISO market as a Generation Resource

Use of Capacity Resources and Transmission

- For their retail behind the meter load that is normally served by their retail btmg, these customers generally only draw on capacity resources and transmission facilities when their retail btmg is experiencing a forced outage/derate or a planned maintenance outage
- Generally, for this type of retail btmg, the probability of a forced outage or derate at the time of the monthly system peaks is very low
- In addition, for some, a portion of their retail behind the meter load cannot operate while their retail btmg is experiencing an outage
- For yet others, a portion of their retail behind the meter load cannot be served while their retail btmg is experiencing an outage

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Excess Generation

- As noted, retail btmg generation is sometimes part of a Qualifying Facility that may either:
  - Have a net output of energy to the retail customer's LSE (settled as part of the LSE's Real-Time Asset Energy for its load) or
  - Provide net capacity and energy as Generation Resource (settled as a Generation Resource)
- This excess generation typically exists due to steam, waste heat or economy of scale reasons
- This excess generation is not serving load at the same electrical location, and, thus, should not be classified as retail btmg
- However, the non-excess portion of the generation facility that is serving retail behind the meter load should still be classified as retail btmg

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Configurations

- There are a number of retail btmg configurations to be aware of:
  - Retail generation and load interconnected by behind the meter distribution level facilities
  - Retail generation and load interconnected by behind the meter distribution and transmission level facilities
  - Retail generation and load interconnected by behind the meter facilities and incidental use of local utility distribution and/or transmission facilities (permitted in some retail jurisdictions)

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Large Retail Customers' Proposed RBTMG and WBTMG Definitions

- We appreciate WEC's efforts to try to better define behind the meter generation
- However, we propose a modification that would classify all behind the meter generation into one of the following two newly defined categories:
  - Retail Behind the Meter Generation (RBTMG)
  - Wholesale Behind the Meter Generation (WBTMG)

Proposed RBTMG Definition

- The portion of generation located behind a retail customer's meter that is:
  - Owned/dispatched by the retail customer, or its agent, to manage the customer's load at the same electric location; and
  - Not registered with MISO as a Load Modifying Resource Behind the Meter Generation (LMRBTMG).

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Proposed WBTMG Definition

- WBTMG includes:
  - All behind the meter generation except for the portion of that generation that meets the definition of RBTMG; and
  - Any portion of RBTMG that is registered with MISO as a LMRBTMG for as long as it is registered with MISO as such.

Proposed WBTMG Registration

- All WBTMG that provides power to load within the MISO footprint, except for WBTMG that has been either certified or self-certified with FERC as a Qualifying Resource, must be registered with MISO as a Generation Resource or LMRBTMG
- WBTMG that has been either certified or self-certified with FERC as a Qualifying Facility and is not registered as a Generation Resource may put energy to its LSE, provided the LSE is required to accept the put (e.g., pursuant to PURPA) or voluntarily agrees to accept the put

Large Retail Customers' Proposal
Netting for Transmission Charges

- We propose that transmission charges for all retail load served behind the meter by RBTMG be based on net load rather than gross load
- Alternatively, at a minimum, such netting should apply to retail load served behind the meter by CHP, other cogeneration or other high capacity factor generation that meets the definition of RBTMG
- We do not take a position with respect to transmission charges assessed to wholesale load served behind the meter by WBTMG except to note that it may be reasonable in certain situations to assess those charges based on net load (e.g., when the load is either not present or cannot be served when the WBTMG is experiencing an outage)

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Rationale

- Vast majority of transmission costs are driven by system peak demand -- not individual customer demand
  - This why these costs are allocated by FERC based on a customer's demand at the time of the system peak and not based on each customer's peak demand
- Netting, over time, averages to the expected contribution to system peak demand on the transmission system by the customer's load that is served behind the meter by RBTMG
- From a transmission planning perspective, there is no difference between a non-RBTMG customer that has a lower demand at the time of system peaks and a RBTMG customer that has a lower net demand at the time of the system peaks due to CHP, other cogeneration or other high capacity factor RBTMG

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In Addition

- The proposal is consistent with FERC's PURPA standby service rule for Qualifying Facilities (18 CFR Ch. I, 292.205 (c))
  - Standby service "(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities."
  - Entergy's analysis from its December 15, 2017 Comments strongly supports that, in aggregate, the net demand of load served behind the meter by high capacity factor RBTMG never approaches gross demand (See Entergy 12/15/17 Comments at 2-3)

Finally

- The proposal is also generally consistent with PJM's FERC-approved approach with respect to transmission charges for retail behind the meter generation (*PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113, *reh'g* denied, 108 ¶ 61,302 (2004))

QUESTIONS?

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Abbreviations

- CHP – Combined, Heat and Power
- FERC – Federal Energy Regulatory Commission
- LMRBTMG – Load Modifying Resource Behind the Meter Generation
- LSE – Load Serving Entity
- PURPA – Public Utility Regulatory Policies Act
- RBTMG – Retail Behind the Meter Generation
- WBTMG – Wholesale Behind the Meter Generation

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BTMG/btmg
Gross Vs. Net Load for NITS Billing

MISO

Planning Advisory Committee

(PAC 003)

February 13th, 2019

PUC Docket 51415
SWEPCO 1st, Q. 1-2
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Purpose & Key Takeaways

- **Purpose:**
- Review stakeholder comments on January proposals (Option 1 / 2)
- Present MISO Revised Conceptual Proposal
- **Key Takeaways:**
  - Option 1 framework preferred by significant majority
  - MISO swayed by arguments for uniform netting for billing associated with retail btmg

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January Meeting Options

Option 1

- Adopt a model similar to PJM
- Distinguish between retail and non-retail behind the meter generation
- Allow for netting of load served by retail btmg where such generation it is at the same electrical location as the load, and the generation does not use the transmission system
- Require NITS customers to designate load for NITS service on the same basis as reported for billing, with respect to retail btmg

MISO

January Meeting Options

Option 2

- Retain existing requirements to report for NITS billing all Load gross of (any known) retail or wholesale behind the meter generation (will necessarily net load for which certain retail btmg of customers is unknown)
- Add a carve-out / waiver for TO ~~grandfathered~~ (historic) practices and/or specifically for QF generation
  - E.g. allow netting at a calculated level that recognizes a reasonable estimate of the maximum coincident demand of the combined QF generation - as some TOs use for planning today
  - PURPA rules seem to support this...

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Preferences by Option

Only one entity favored Option 2

Entity	Option 1	Option 2
WPPI	X	
Entergy	X	X
TOs (not Ameren/MRES/GRE?)	-	-
Invenergy	X	
Eligible End-Use Customers	X Preferred / With mods	X With mods
MRES/Ameren	X	
GRE		X
LEUG (Kean Miller LLP)	X	
NIPSCO	X	
WEC	X?	

MISO

Summary of Stakeholder Positions

Strong support for Option 1 netting for retail; Planning and use by QFs consistent; retail "ownership" not needed; allow some incidental T use; avoid treatment of distribution

- **WPPI favored Option 1 -** most stakeholders support netting for retail; retail btmg is often tied to load; PJM shows FERC will consider netting
- **Entergy finds Option 1, or 2 acceptable –** netting of QF gen is consistent with FERC policy; gross load is never used by customers with QF generation; Entergy does not plan for gross load. FERC treatment for billing different than for designation if not discriminatory and netting results in cost allocation that is more consistent with cost causation and/or promotes demand response programs.
- **MISO TOs (except AMEREN, MRES, GRE) do not take a position** on either Option; Argue that a definition or RBTMG should be based on generation "used to manage" load, not "owned and dispatched by" retail customer to manage load; (why?)

  A sub-category of Behind the Meter Generation that serve a retail is owned and dispatched by a retail customer, or its agent, to manage the customer's load at the same electric location

  If Option 1, allow for infrequent t use of the transmission system when load dips below retail generation; MISO should not speak to use of the distribution system as outside of jurisdiction.

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MISO

Allow Incidental use, Not "grandfathered" term; OK with targeted Hi CF generation types; exempt load not served

- **Invenergy supports Option 1** on the basis that loads that do not use the system should not pay for it.
- **Eligible End Use Customers prefer Option 1 as** "a good starting point"; strong stakeholder support;
- Agree with TOs to allow some incidental use of the transmission system with consent of TO; open to limiting "incidental" use to between adjacent common customer facilities;
- Do not use "grandfathered practices" as excludes similarly situated generation going forward;
- OK with Option 2 with waiver from gross load reporting for CHP, other cogeneration or other high capacity factor generation; or, alternative where MISO would maintain the status quo allowance in MISO South to net load served by QF btmg, but otherwise leave to local regulators whether gross or net for retail btmg is appropriate. This maintains the status quo; add exemption from gross for "LMRBTMG" if load trips with generation, or can't be served by supply resources on the MISO system when the generation is on outage.
-

MISO

Coincident use for billing not in question; Non-conforming load indistinguishable from netted load.

- **Eligible End Use Customers comments to other stakeholder October positions:**

  MRES and Ameren Transmission …disagrees that just because a customer does not have a net withdrawal from the system at the time of the coincident peak does not mean that the customer is not using the transmission system. As noted previously, the transmission system serves customers at other times and in other ways than just at peak for the delivery of capacity.

  End Use Sector argues that the task before the MISO PAC is not to revisit 12-CP pricing for Schedule 9 transmission services under the MISO Tariff, but how to apply that practice to retail and wholesale load served by generation behind the meter. Customers with non-conforming load, load that peaks at a different time than the system peak, inherently place greater demand on the transmission system in non-system peak hours than during system peak hours that determine their Schedule 9 transmission charges. These customers are not subject to restrictions on the use or additional charges for the demand during those non-system peak hours that is in excess of their coincident peak demand. The transmission system sees no difference between greater demand being placed on it during off-peak hours by non-conforming load than it does by greater demand being placed on it during off-peak hours by retail load served behind the meter by CHP, other cogeneration facilities and other high capacity factor generation.

Reasonable to treat wholesale and retail gen differently; Retail rarely dispatched based on market economics as Network Resources are

- **Eligible End Use Customers comments to other stakeholder October positions:**

  MISO should not create a new definition for load served by retail behind the meter generation for purposes of treating it differently from wholesale BTMG as it could be seen by FERC to be discriminatory. FERC explicitly recognized this potential discrimination in its 2005 Order of the PJM proposal on BTMG netting in ER04-608.

  Extending netting for all wholesale btmg is problematic because most wholesale btmg is not operated in the same manner as most retail behind the meter generation. Thus, they are not similarly situated and it is not unduly discriminatory to treat differently.

  Most wholesale behind the meter generation is committed and dispatched by its owner based on market economics to meet load behind the meter. there can be a large number of hours when the generation is not used to serve load when available, but it is more economic to supply the load from the market via the transmission system. This makes the operation of this generation almost indistinguishable from the operation of Network Resources in the market. It is this specific situation that we believe is the driver behind gross load for wholesale behind the meter generation and the prohibition on partial designation of load at a delivery point under Order Nos. 888 and 890.

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Retail generation supplied load rarely uses the transmission system; Justifies a different treatment for this generation

- **Eligible End Use Customers comments to other stakeholder October positions:**

  retail gen is not operated based on economics but wherever available and transmission system is only utilized to serve that load when the retail behind the meter generation is on an outage. CHP, other cogeneration and other high capacity factor retail behind the meter generation typically have very low (5% or lower) equivalent forced outage rates. As a result, the number of hours in which the transmission system is used is small and primarily during off peak times of the year when maintenance is being performed on the generation. In our opinion, it is these operational characteristics, that are very different from the operational characteristics of Network Resources and most wholesale behind the meter generation, that underlie FERC's PURPA standby service rule for QFs (18 CFR Ch. I, 292.305 (c)). They also justify a different treatment for retail behind the meter generation, especially CHP, other cogeneration and other high capacity factor generation serving retail load behind the meter, than for wholesale behind the meter generation.

Important to treat retail and wholesale generation similarly; uniform netting rules for footprint; FERC has accepted netting if non-discriminatory and reliable

- **AMEREN and MRES prefer Option 1** (Tariff revisions similar to PJM) so long as retail and wholesale BTMG are treated similarly and the rules apply uniformly across the footprint. PJM shows FERC is willing to deviate from their positions in 888/890 so long as the proposed netting is applied non-discriminatory basis across the RTO footprint and that the RTO can show that there are no reliability/planning concerns resulting from the proposed BTMG netting treatment; Option 2 appears to be discriminatory between areas, and past practice is not a good reason; encourage MISO and the stakeholders to clarify rules and to bring those changes to FERC so all operating under the same assumptions across the MISO footprint.

Not feasible to align planning and net billing; Standby has a cost; Cost shifts based on level of btmg not equitable

- **GRE has significant concerns with Option 1, and could support Option 2** with mods;
- Align transmission cost allocation with investment causation; how can a NITS customer designate only part of the load for planning (i.e. that part that would be netted for billing); to maintain reliability, the NITS customer would designate the maximum load, which would then necessarily conflict with the billing only for net load, shifting costs to other customers; Reliability is compromised every time the load exceeds this average;
- Baseload resources may pose lower risks to reliability but if transmission system serves as firm backup for the generator there is a cost and shifts costs to other customers; It is difficult to see how to plan for part of the load and still provide firm and reliable standby capability;
- Exempting some retail generation based on technology (ie baseload) may be seen as discriminatory, particularly as technologies improve and evolve.
- Support existing rules to report gross load for NITS billing, outlined in Option 2, but MISO should enact consistency and accountability in application of rules particularly when it comes to reliability and planning. (Reliability principles should not be subject to individual TO's interpretation)
- Utilities with large quantities of BTMG (whether due to customer preferences, state policies or mandates) would be shifting costs to utilities with small quantities of BTMG; transmission cost share should not depend on amount of BTMG utility has on aggregate;
- Some behind the meter load is currently unknown, and will necessarily be netted in spite of NITS customer's best efforts

Option 1 best …

- **LEUG confirms its preference** and support for its previous comments understood to be consistent **with the Option 1;** also opposed to a "grandfathering" suggested in the Option 2 as inconsistent with QF rights under PURPA; opposed to deletion of the words "or transmission" from the definition of Retail Behind The Meter Generation, as it would be inconsistent with configurations today which include incidental use of transmission in some circumstances.
- **NIPSCO supports Option 1** – the netting of load for NITS charges similar to what PJM has in place as generally supported by Stakeholders based on previous PAC feedback from September 26, 2018. Also support the MISO Transmission Owners feedback; Option 2 more complicated and insufficiently detailed – more work.

Differentiate between wholesale and retail; Option 1 less confusing and FERC has accepted similar

- **WEC continues to support a policy that differentiates between wholesale (non-retail) and retail BTMG. Option 2 does not make this distinction and further complicates the BTMG issue.**
- Option 2 would not allow any netting of "known" BTMG, whether wholesale or retail; Oppose Option 2 as will "retain existing requirements to report for NITS billing all Load gross of any known retail or wholesale behind the meter generation"; states there are no existing tariff or BPM requirements to gross up network load for any type of BTMG; This fundamental issue is responsible for wide-spread differences in the treatment of BTMG throughout the MISO footprint and over a decade of debate and frustration.
- Oppose use of "known" btmg, as subject to interpretation and leads to further confusion;
- Regarding MISO's concern that Option 1 is not consistent with FERCs prohibition on the partial designation of load at a delivery point, FERC did approve the PJM methodology and will likely consider proposals that are not in strict compliance with prior orders, especially within ISOs.

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MISO positions supported…

MISO is persuaded by the following arguments of stakeholders:

- Option 1 is strongly preferred.
- Billing for load gross of all retail btmg is not practical nor consistent with actual use, or grid investment caused by load – particularly where the generation is CHP, other cogeneration or other high capacity factor generation.
- MISO should address the occasional or incidental use of the transmission system by the btmg (in a manner TBD) but should not address use of the distribution system which is neither MISO nor FERC jurisdictional.
- There are differences between the requirements for designating load for establishing NITS service and the allocation of costs for NITS service. The MISO tariff and FERC precedent allocate costs based on withdrawals (usage) at the time of coincident peak (12 CP load). These coincident withdrawals cannot be guaranteed to apportion costs in a manner that is commensurate with proportional grid investment whether due to gross load variations (load factors) or btmg operation.

MISO positions supported …(2)

- There are differences in the usual operation of retail btmg and non-retail btmg (owned by municipal electric systems, electric cooperatives, or electric distribution companies) to serve load that warrant different netting treatment. Retail generation is not likely to be used in an economic manner relative to market operated Network Resources.
- Netting should be applied to ANY btmg that either has its associated load tripped with loss of the generation, or otherwise has by design insufficient supply from the transmission system to support its associated load.
- The netting policy should apply uniformly to all NITS customers under the MISO wholesale transmission tariff

MISO

MISO positions supported ...(3)

- Allowing costs for NITS service to be billed based on coincident load net of retail behind the meter generation is an allocation issue and will not compromise reliability
- Allowing netting of retail generation on a non-discriminatory basis for all NITS customers is practical and will not shift costs between customers, except as may happen from month to month based on load variations whether these are due to load alone or varying amounts of retail generation
- NITS billing practices should not discourage use of retail generation to minimize demands on the system

Next Steps

- Revisit draft tariff and BPM language for netting of RBTMG
- Discuss
- Revise
- File

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